

SUMMARY OF THE WESTERN WIND AND SOLAR INTEGRATION STUDY STAKEHOLDER MEETING

July 30, 2009
Embassy Suites Hotel Denver-Aurora

The following is a summary of the presentations and the discussion at the Western Wind and Solar Integration Study (WWSIS) stakeholder meeting that took place on July 30, 2009 in Denver, CO. Presentations can be accessed at <http://wind.nrel.gov/public/WWIS/stakeholder%20meetings/7-30-09/>. A list of meeting attendees and participants via conference call is provided in Appendix A.

Executive Summary

The WWSIS is designed to look at the operational impacts of increasing amounts of wind and solar in WestConnect, a group of transmission owners in Arizona, Colorado, New Mexico, Nevada, and Wyoming. The WWSIS examines the impacts of three penetration levels of renewables: 10% wind/1% solar both within the WestConnect footprint and outside WestConnect; 20% wind and 3% within WestConnect and 10% wind at 1% solar outside WestConnect and 30% wind and 5% solar within WestConnect and 20% wind and 3% solar outside of WestConnect.

The stakeholder workshop focused on preliminary results for three scenarios: In Area, Mega Project and Local Priority. In addition, NREL and General Electric (GE) requested input from stakeholders on what future scenarios to study. Presentations on WWSIS were given by Debbie Lew of NREL on the overall project and next steps; Dick Piwko of GE on the project work plan and study scenarios; and Lavelle Freeman, Gary Jordan and Nick Miller (all of GE) on the statistical analysis; production simulation analysis; and intra-hour variability and uncertainty, respectively. Charlie Smith of the Utility Wind Integration Group (UWIG) led the discussions on the results and additional proposed scenarios.

Preliminary findings discussed at the workshop include the following:

- GE's production simulation analysis indicates that 30% wind and 5% solar penetration is technically feasible.
- Impacts are more severe at 30% wind and 5% solar inside WestConnect and 20% wind and 3% solar
- There is significant monthly and seasonal variation of wind and solar energy within the WestConnect footprint and across areas
- Wind forecasts are critical
- Higher levels of demand participation will be critical at higher levels of wind and solar penetration
- The daily coincidence of wind and solar with load leads to periods with high ramping requirements
- Intra-hour variability increases with wind penetration levels, with the bigger the impact of variability on the smaller the area

Next steps on WWSIS include the following:

- Start looking at additional scenarios and analysis. The original plan was to analyze two additional scenarios such as high solar penetration, high geographic diversity, or high load correlation. The three scenarios studied so far show very little variation between them, making the high geographic diversity and high load correlation scenarios unlikely to be very interesting. A lack of quality solar data at fast timescales makes it difficult to examine high solar penetrations.
- Examine the 20% wind and 3% solar in both in-footprint and out in order to understand whether the differences between our 20 and 30 case are due to the in-footprint or out-of-footprint changes.
- More options include: investigate the value of energy storage; change the non-renewable portfolio mix; incorporate greater levels of demand response; assess plug-in hybrid electric vehicles; examine implications of market operations and higher levels of wind and solar generation; and carbon pricing sensitivity analysis.

Introduction by Debbie Lew, NREL

Debbie Lew of NREL is the WWSIS project manager. She presented an overview of the project and discussed some issues and major tasks. The goal of WWSIS is to understand the costs and operating impacts due to the variability and uncertainty of wind and solar power on the WestConnect grid, not the cost of wind or solar generation. The study scope includes operations, not transmission, projected to the year 2017, which lines up with WECC studies. The study seeks to stimulate load and climate of the years 2004, 2005, and 2006, projected to 2017.

The issues the WWSIS is designed to investigate:

- Whether balancing area cooperation or virtual control area assistance can aid in integrating variable renewable energy generation;
- The role of storage in integrating variable renewable energy generation;
- The impact of increased levels of variable renewable energy generation on reserve requirements;
- Whether spreading out variable renewable energy generation geographically aids in integrating such generations; and
- The role of hydro in integrating variable renewable energy generation.

The major WWSIS tasks include data collection and development, running three complete scenarios, with additional scenarios to be identified and analyzed. A lot of work went into developing the datasets, which are critical inputs. The wind dataset was very large and had to be revised due to issues with unrealistic ramps. A workaround was developed to address increased variability caused by data 'seams' occurring every third day. The wind data was validated against meteorological tower data and wind plant outputs. A lot of effort also went into developing a solar dataset, which was made difficult due to a lack of solar data. A satellite cloud cover model was used to produce 10 km hourly solar radiation data and noise was introduced to develop 10 minute data reproducing variability of measured PV plants. The CSP was modeled

with 6 hours of thermal storage, which eliminated the need to model 10 minute CSP output. All of the data can be accessed at the WWSIS website.

After this stakeholder meeting, GE will complete analysis of the three scenarios presented today and construct and analyze two additional scenarios. A draft report is expected by the end of 2009, with a final report in February 2010. Another stakeholder meeting will likely take place about that time.

Dick Piwko, Project Overview & Scenario Description

Mr. Piwko outlined the WestConnect study footprint, which consists of the service territories of the following entities: Arizona Public Service, El Paso Electric, NV Energy, Public Service of New Mexico, Salt River Project, Tri-State G&T, Tucson Electric Power, Xcel Energy, and part of WAPA. The WWSIS project objective is to help multiple utilities in the western U.S. understand the costs and operating impacts of the variability and uncertainty of wind and solar power on their grids and potential mitigation options for these impacts.

The project is well along through the work plan, having mostly completed the analysis for the three primary scenarios. Additional scenarios and analysis will be conducted during the next few months, with a draft report due in December 2009, and a final report expected by February 2010.

Mr. Piwko noted that variability and uncertainty are two different concepts. Variability involves changes over time. Wind and solar generator outputs vary as the intensity of their energy sources changes over several timescales including minutes (regulation), hours (ramping), diurnal, and seasonal. Uncertainty involves unpredictability, with the output predicted by a forecast. Wind and solar are similar to load in this respect, as the actual power output is different than the forecasted output. A perfect forecast can eliminate uncertainty, but there will still be variability.

The wind dataset for this project was very large, covering all of the Western Interconnection and including 30,000 30-MW sites with 3 years of 10-minute wind data for each. There were also 500 to 600 100-MW solar sites. Not all of these sites were used in the study. The study escalated electric loads for 2004, 2005, and 2006 to the study year of 2017. The wind and solar combinations were as follows:

- 2017 Baseline: Preselected existing wind and embedded solar.
- 30% In-Area: 30% wind and 5% solar in-footprint (WestConnect)
 20% wind and 3% solar out-of-footprint
- 20% In-Area: 20% wind and 3% solar in-footprint
 10% wind and 1% solar out-of-footprint
- 10% In-Area: 10% wind and 1% solar in-footprint
 10% wind and 1% solar out-of-footprint

The solar portion consists of 70% CSP with 6 hours of storage and 30% PV.

The first scenario was the In-Area scenario, in which each transmission area (roughly correlates to state, except for Colorado which is divided into east and west) in the WestConnect footprint meets wind and solar penetration targets using resources within that transmission area. For each state, GE ranked wind and solar sites according to the following screening criteria – capacity factor, capacity value, and location. Sites then were selected in each state starting from the

highest ranked sites until the required energy targets were met for each penetration level. For the 30% scenario, 998 wind sites were selected with a total installed capacity of 29,940 MW, and 29 CSP and 29 PV sites, both with total installed capacities of 2,900 MW. This resulted in 100,594 GWh of renewable energy for the year 2017, which is 35.2% of the projected 285,979 GWh needed to serve load.

The other two scenarios are variations on the In-Area scenario. The algorithm used to build the Mega Project and Local Priority scenarios displaces less valuable sites from one area, making that area a net importer, with the energy from more valuable sites in another area, making that area a net exporter. The total renewable energy is held constant and the costs of generation equipment, new transmission and losses are minimized. The site selection and transmission reinforcements from the algorithm are manually adjusted to reflect practical constraints. The Mega Project scenario maximizes the cost benefit and the Local Priority scenario approximates local benefits by reducing the cost of capital in importing areas by 10%. The Local Priority scenario ends up about halfway between the In-Area and Mega Project scenarios.

The Mega Project scenario takes out some of the marginal wind sites, mainly in Arizona, adds some better wind sites, mainly in Wyoming, and builds a series of high-voltage transmission lines. The result is 801 wind sites for 24,040 MW, 5,700 MW of solar, 6,900 GW-miles of new transmission, including a 600-kV DC bipole transmission line from Wyoming to Arizona, and a \$1.2 billion reduction in total capital costs as compared to the In-Area scenario. The Local Priority scenario has the same trade-off but to a lesser degree and ends up with 872 wind sites for 26,160 MW, 5,700 MW of solar, 2,100 GW-miles of transmission, but without the DC bipole, and a \$3 billion reduction in total capital costs as compared to the In-Area scenario.

The scenarios incorporated transmission projects that are already underway or have been proposed. GE tried not to speculate too much on specific transmission projects. For the projected transmission paths, GE also tried to respect existing transfer limits and transmission constraints. The outcome does not represent any state policies, but tried to stay with general concepts, as this is not meant to be a planning study.

Overall, Mr. Piwko said the production simulation analysis indicates that 35% energy penetration of wind and solar generation is technically feasible. The technical details of the statistical analysis, production simulation analysis, and quasi-steady-state (QSS) analysis show how the system operations are affected, which are dramatically different from what is typical today. Mr. Piwko concluded by noting that:

- “Can you do this?” is the focus of this study
- “What do you need to do to get there?” is explored to some extent
- “Should you do this?” is a policy and economic issue and beyond the scope of this study, which is why they have not looked at any specific projects or state plans.

A comment was made about how the study seemed to be biased against solar as there are huge solar resources in Arizona that could meet much more of a renewable requirement. Mr. Piwko notes that this started out as a wind only study and solar was added later. He said the problem with including more solar is that they do not have access to good solar data. The small amount of solar data they do have has already been stretched to include the 5% penetration. NREL and GE were uncomfortable trying to extrapolate this data even further as it would lead to a study that

was based on too much speculation and little data integrity. They would like to explore higher solar penetration cases if they could get more solar data.

Lavalle Freeman, Statistical Analysis Part 1 – Seasonal, Monthly, Daily Trends

In Part 1, Mr. Freeman presented a high level overview of the statistical analysis, with seasonal, monthly, and daily trends for all three scenarios. The main observations in his presentation are:

- There is significant monthly and seasonal variation of wind and solar energy within the WestConnect footprint and across areas:
 - Penetration and variation issues less severe over large areas
 - 30% is not always 30%
- The daily coincidence of wind and solar with load leads to periods with high ramping requirements:
 - Results in impacts on net load peaks and valleys and an increase in ramps
 - Ramping issues less severe over large areas
- Hour-to-hour variability:
 - Load is a significant contributor; wind and solar increase ramps at various times of day
 - Mitigated over wide areas by spatial/temporal diversity
- Predictability of wind (day-ahead forecast error):
 - Forecast error is not a linear function of the wind forecast

Mr. Freeman noted there had been some data issues with respect to the data seams. 3TIER, the mesoscale modeler for WWSIS, had taken 3-day data intervals and stitched them together at 4 pm every three days. This had the unanticipated effect of creating more variability at that time period. For the statistical analysis only, GE ended up taking out every third day to eliminate this artificial ramping effect. Therefore, the statistical analysis will focus on two-thirds of the year. Energy calculations and data counts are scaled up by 50% but average profiles and duration plots are relatively unaffected, and percentage and per unit results are the same.

Mr. Freeman compared monthly energy generation for PV, CSP and wind for all three scenarios. At 30% wind and 5% solar, the monthly energy from wind and solar in the WestConnect footprint for each of the three years projected to 2017 show significant variation. In some months, the 2006 data leads to much higher monthly generation than the other two years, with the reverse happening in other months. There is a notable difference between wind and solar energy across the months and over the years. A comparison of the monthly energy from wind and solar for the three scenarios shows that there is very little variation between the scenarios; at the 30% wind or 5% solar penetration levels, the month to month variation dominates. The main finding to note is that 30% is not 30% all the time, not even in every month, but is an average value over the year. For example, the 2006 data for the In-Area scenario leads to ranges of 18% wind and solar energy in July to 55% in April, for the In-Area scenario. Additionally, an examination of the total and percentage of monthly energy from wind and solar for different states shows that area size is important. Large amounts of wind in small areas will lead to balancing issues. For example, in the Local Priority scenario, Wyoming has a lot of wind

capacity and a small load. In January, projected wind energy output was 189% of the projected monthly load in Wyoming for the Local Priority scenario of the 30% wind, 5% solar penetration levels.

Mr. Freeman then presented some yearly duration plots. A plot of the net load duration for the 2006 dataset for the In-Area scenario shows that at 30% wind and 5% solar, net load is below the existing minimum load for approximately 57% of the year at the 30%, penetration levels. Additionally, for about 24 hours in a year, net load goes negative, i.e. there is more wind energy than load. A plot of all three scenarios shows there is no significant differentiation in net load duration curves at the footprint level. A look at some specific states shows:

- Arizona is below existing minimum load about 45% of the year for In-Area scenario at the 30% wind and 5% solar penetration levels.
- New Mexico is below existing minimum load about 60% of the year for the Local Priority scenario at the 30% wind and 5% solar penetration levels.
- Wyoming is below existing minimum load about 90% of the year and in a negative net load for 65% of the year in the Mega Project scenario at the 30% wind and 5% solar penetration levels.

Mr. Freeman presented several plots of wind duration curves in the WestConnect footprint for the three scenarios. There is a marked variation in the duration curves by state due to the differences in the wind quality, with areas with higher quality wind resources having a flatter annual wind duration curve. For the Local Priority scenario at the 30% wind and 5% penetration levels, the maximum instantaneous penetration level is in the table at right.

Area	Max Inst. Penetration
Colorado-West Wind	75%
Wyoming Wind	286%
New Mexico Wind	110%
Colorado-East Wind	85%
Nevada Wind	71%
Arizona Wind	101%

Mr. Freeman also presented some daily profiles and time series plots. He noted that the average daily profiles do tend to obscure a lot of things, i.e., those details that are happening at the extremes. The load and wind average daily profiles for all three scenarios at 30% wind penetration are quite different for each month. The months shown in the plots are January, April, July, and October. In January, load and wind are relatively flat, with wind having two small humps in the early morning and in the late evening. In April, wind generation tends to rise during the day, then falls off slightly, which is quite similar to load. In July, load is rising during the day, while wind output is falling off. In October, load is relatively low and there is lots of wind generation, with wind higher than load over portions of the day.

Plots showing solar output and load are very different as solar has a very different profile from wind. In January, both CSP and PV are only producing between about 7 AM and 6 PM. In April, CSP with storage lasts the full 6 hours, while PV starts ramping up at 5 AM and ramps back down to zero by 6 PM, with both higher than load at their maximum levels. In July, PV and CSP correlate quite nicely with load ramping up and down. In October, both PV and CSP have reduced output levels again.

Mr. Freeman concluded Part 1 with a series of plots showing total load, wind and solar variation for the WestConnect footprint in the months of April and July for the Local Priority scenario at 30% wind and 5% solar penetration levels. The plots in April show that at one point wind is higher than load. Also, solar tends to ramp down when wind is tending upward. A plot of load and load minus wind and solar shows that a large degree of variation comes from load. The July plots show much lower levels of wind and solar production, with wind contributing significantly less energy.

Gary Jordan, Operational Impacts – Part 1

Mr. Jordan's presentation consisted of an overview of the operational assumptions, study assumptions, annual operational impacts, and hourly commitment/dispatch results for selected weeks. The main observations from this section are:

- Wind forecasts are critical – significant variations in impact for the same wind variability with different forecasts.
- No significant issues at penetrations up to 20% wind/3% solar in the WestConnect footprint and 10% wind/1% solar outside WestConnect.
- Impact more severe at 30% wind/5% solar inside the WestConnect footprint and 20% wind/3% solar outside of WestConnect.
- Operational impact dependent on what your neighbor is doing areas – if one area has a lot of wind and another doesn't, then the variation can be spread around, but if both areas have lots of wind, then it can lead to conflicts.
- At higher penetrations, it is essential that demand is an active participant – at higher levels of variability, load has to be an integral player.

The study assumptions for the operational analysis of the In-Area scenario were reasonable when the project began two years ago. The 2017 projected fuel prices were \$2.00/MBtu for coal and \$9.50/MBtu for natural gas and carbon was set at \$30/ton. The \$9.50 price for natural gas seems high now following the economic slowdown and discoveries of new shale gas domestic supplies. This is something that GE will need to look at and perhaps conduct some sensitivity analysis with respect to fuel prices. For capacity additions, they used the Energy Velocity Database and added 24 GW of capacity between the 2009 to 2017 timeframe to maintain adequate reserves. Peak load projections from the North America Electric Reliability Corporation (NERC) were used, which has been updated by NERC at the end of last year to reflect the economic slowdown. GE's model reflects "economically rational," WECC-wide commitment and dispatch while recognizing transmission constraints. Wind is assumed to enter the market as a price taker. The operational analysis looks at spot price duration curves for all cases, unserved energy, and generating unit starts.

A note about wind forecast error and case naming convention. The wind forecast error varied annually and regionally. GE looked at two wind forecast scenarios, one that assumes a perfect wind forecast and one that used a reduced wind forecast where the in-study footprint forecast was reduced by 10% and the outside forecast by 20% to create an unbiased forecast. GE used the following naming convention: Scenario – Penetration – Forecast – Sensitivity. For example:

I20Rt is In-Area, 20% wind and 3% solar penetration, reduced wind forecast, transmission sensitivity.

Mr. Jordan presented a series of slides showing results for the In-Area scenario. First were annual spot price duration curves for both the perfect wind forecast and the reduced wind forecast. At increased levels of renewables under a perfect forecast, spot prices are driven lower. Wind forecast errors, however, drive spot prices back up above a 20% wind penetration level. At lower wind penetrations, the wind forecast differences do not have a large enough effect, but at higher wind penetration levels, wind forecasts start affecting unit commitment to a larger degree. Over-forecasting wind means not enough units are committed for the next operating day, and the difference needs to be made up in real-time using more expensive peaking units.

An examination of generating unit displacement as a function of high levels of wind and solar penetration shows that the biggest impact is reduced combined cycle generation, as these are the marginal units. Coal is not displaced until much higher penetration levels of wind and solar, and it is modest compared to the impacts on combined cycle generation. Significant operating cost savings result from adding of renewables, around \$8 billion in total for 10% wind and 1% solar penetration levels and increasing up to \$20 billion at the 30% wind and 5% solar penetration levels. Wind forecasts also add value due to reduced operating costs, approximately \$1 to \$2 per MWh. The incremental value of wind and solar generation based on spot price revenue ranges from \$80/MWh for 10% wind/1% solar penetration to \$30/MWh at 30% wind/5% solar penetration. Solar offers slightly higher incremental values due to its correlation with high load periods during the day.

The total amount of generation in the WestConnect study area remains fairly constant as the mix of resources changes. The plot also shows the effect of increasing WECC wind generation outside of WestConnect to 20%, which results in a drop in exports. A significant portion of the drop in generator revenue in the study area when moving from 20% to 30% penetration comes from the WECC-wide change and the export reduction.

Mr. Jordan noted that higher wind penetrations resulted in significant increases in unserved energy due to occasional over forecasting of the wind generation. GE ran some additional cases for the In-Area 30% wind/5% solar scenario where the annual unbiased wind forecasts were discounted an additional 5% each time, up to a 25% discount. This led to some interesting results:

- Discounting the wind forecast drives spot prices down across the entire year.
- Very little spilled and unserved energy until the wind 30% wind/5% solar penetration levels.
- The hourly unserved energy increases steadily as the wind forecast is discounted.
- The results show that interruptible load is more than cost justified.
- With about 2,000 MW of interruptible load, it would need to be interrupted about 40 to 50 hours per year.

Mr. Jordan said most of the results presented were based on the 2006 data but there was very little difference between these results and those from 2004 and 2005.

The weekly operational analysis examined the hourly operation for two specific weeks in mid-April and mid-July. The results show hourly variation in generation by type as wind and solar penetration increases. The plots of dispatch in WestConnect for the week in April show there is not a lot of impact at the 10% wind/1% solar and 20% wind/3% solar penetration levels, but large changes occur at the 30% wind/5% solar penetration levels, as wind was strong in April. Wind production is much less in July, so there is minimal impact from wind at 10% and 20% and only slightly higher impacts at 30%. As noted before, 30% is not 30% in every month. Therefore, operational impacts are worse in some months, and as before, not a lot variation between years.

Mr. Jordan also presented some results showing the changes in unit starts for combined cycle and coal plants. The unit starts for combined cycles steadily increased while capacity factor and hours of operation decreased as penetration levels increased. Coal unit starts did not increase until at 30% wind and 5% solar.

GE also examined the impact of additional scenarios where energy generation was held constant but the total installed capacity and location was varied. The results show there is no significant variation in operational results between the scenarios.

A stakeholder asked how much of the operational results depended on the flexibility of gas units. Mr. Jordan said this was not a factor. Mostly, what happens is 3,000 MW of combined cycle generation gets backed out. Mr. Piwko said GE may do some sensitivity cases where they decommit units and investigate the impacts, such as taking out 6,000 MW of combined cycle and adding 3,000 MW of simple cycle. But ideally, it would better for load to participate.

Lavalle Freeman, Statistical Analysis Part 2 – Hourly Variability and Day-Ahead Predictability

Mr. Freeman started the presentation by outlining the statistics used to characterize variability:

- Delta – the difference between successive data points in a series, or period-to-period ramp rates. A positive delta is a rise or up-ramp. A negative delta is a drop or down-ramp.
- Mean – the average of the deltas.
- Sigma – the standard deviation of the deltas.

For a normal distribution of deltas, sigma is related to the percentage of deltas within a certain distance of the mean.

The scatter plots of wind deltas versus load deltas for the Local Priority 30% wind/5% solar scenario led to these observations:

- Wind deltas versus load deltas in the spring show no obvious causation.
- Wind versus load deltas for all seasons show 3 hours during year where net load down-ramps more than the largest load-alone down-ramp, and 66 hours where net load up-ramps more than largest load-alone up-ramp, i.e. wind pushes load.
- Wind can exaggerate down ramps.

- There are certain times of the year and certain seasons where ramps are more pronounced.

The average daily profiles of deltas over a year show that the 10% wind/1% solar and the 20% wind/3% solar penetration levels do not affect the system very much more than normal load variability. At 10% wind/1% solar, the maximum one-hour rise is 4,178 MW and the maximum one-hour drop is 4,195 MW. The maximum one-hour rise and one-hour drop are only slightly larger for the 20% wind/3% solar case. The 30% wind/5% solar case, however, has more noticeable impacts, with a maximum up ramp of 5,644 MW and a maximum down ramp of 4,931 MW. Additionally, in all cases, the extreme ramps tend to occur in the early morning and early afternoon hours. The plots of variability for different states show that Arizona and Wyoming seem to be the most affected. Wind variability actually overwhelms load variability in Wyoming and tends to drive variability in the entire WestConnect footprint.

Mr. Freeman also presented some plots of selected days with extreme one-hour up-ramps and down-ramps for the Local Priority 30% wind/5% solar scenario. On November 14th, there is a 2,025 MW/hr up ramp in load, while wind is down-ramping by 1,600 MW/hr and CSP is down-ramping 1,700 MW/hr, all causing a 5,644 MW/hr up-ramp in net load in the WestConnect footprint. This occurs in the late afternoon period, which seems to be the most active time of the day.

Plots of up-ramps by time of day and month show that wind and solar production decreases drive extreme up-ramps in the late afternoons during the fall and winter. Also, extreme down-ramps in the summer are driven by the early evening load roll-off. The distribution of net load deltas shows that at 30% wind/5% solar, there are significantly more extreme net-load deltas beyond the largest load delta, especially for up-ramps:

- Local Priority – 6 down-ramps of 4,400 MW/hr or more and 152 up-ramps of 3,600 MW/hr or more.
- Mega Project – 31 down-ramps of 4,400 MW/hr or more and 131 up-ramps of 3,200 MW/hr or more.

There are more and larger down-ramps with the concentration of wind in Wyoming in the Mega Project scenario. The duration of extreme hourly net load deltas shows that ramps do not occur at the same time. Ramps are mitigated by spatial and resource diversity. This makes the case for wider balancing areas, as the greater the diversity in the location of variable resources, the less the relative variability.

Mr. Freeman also discussed day-ahead predictability. A scatter plot of next day wind forecast errors versus wind forecasts showed that the wind forecast error is not a linear function of the wind forecast, a not entirely unexpected result. This shows that discounting the wind forecast to increase spin does not appear to be a good option.

Mr. Freeman ended his presentation by noting that the key take-aways from this analysis are:

- There is significant monthly and seasonal variation in wind and solar energy generation within the WestConnect footprint and across areas.
- Relatively small observable differences among scenarios, but they are more pronounced at the area level.
- The coincidence of load with wind and solar is a large driver of diurnal variability.

- At the footprint and area level, net load variability tends to be high during fall and winter late afternoons due to the simultaneous rise in load and the reduction of wind and solar generation.
- There is a good case to be made for load participation in reducing ramp requirements.
- Wider balancing areas lead to greater diversity, less relative variability and extreme ramps.
- The wind forecast error is not a linear function of the wind forecast. Therefore, discounting the wind forecast to increase spin may not be a good option.

Gary Jordan, Operational Impacts – Part 2

In Part 2, Mr. Jordan discussed conventional hydro operations, pumped storage hydro operations, fuel price sensitivity, transmission flows, and transmission sensitivity. He also presented some results from the reliability analysis.

Mr. Jordan presented plots showing the WECC-wide hydro operation for a week in April and a week in July, at all wind and solar penetration levels. GE's analysis respected the minimum and maximum generation levels and energy availability for each hydro plant. The plots show that hydro does not do anything much more than it already is. Hydro plants make output adjustments on a regular basis as they follow load, and there is not a lot difference in this respect when more renewables are added. Hydro power can also follow forecasted wind power. There is also very little change in total hydro output, nor does the change in hydro dispatch greatly affect spot prices. There is however, a cost to not shifting hydro output in response to wind. The analysis projected that at 30% wind/5% solar penetration, operating costs increase by about \$200 million if hydro does not adjust for wind variability.

The results of GE's analysis on pumped storage hydro (PSH) output indicate that there are already adequate amounts of PSH in the system. At higher wind and solar penetration levels, the existing PSH is used more but there is no strong incentive to add more PSH units. GE examined the effects of forcing more PSH but found that total variable costs increased slightly. This was partly due to the spot price reduction effects of adding more price-taking wind and solar into the market.

Mr. Jordan then presented some information regarding fuel prices. When GE started this project, the \$9.50 per MMBtu natural gas price they decided upon seemed reasonable at the time. Since then, the economic downturn and the discovery of additional natural gas supplies have led to a large drop in natural gas prices. At the end of April 2009, natural gas was \$3.50 per MMBtu. He also noted that GE's analysis used a carbon price of \$30/ton, which adds \$0.60/MWh to combined cycle costs and \$1.00/MWh to coal production costs.

GE conducted some additional runs with natural gas at \$3.50 per MMBtu to examine the relative operational impacts. Under this price scenario, coal units start to get displaced much sooner and to a much larger degree at 30% wind/5% solar than before. Additionally, because coal is being displaced, emission reductions are larger. Total operating cost savings however, are reduced, as wind is now replacing a cheaper fuel.

Mr. Jordan presented some bubble maps of transmission path flows by path and by scenario. These generally showed increases in transmission flows, especially in the Mega Project scenario, which is expected since the Mega Project has significant transmission additions as part of the scenario. The transmission sensitivity analysis examined the Local Priority and Mega Project scenarios without the addition of any new transmission. This resulted in large amounts of spilled energy, up to 20% of the wind generation in WestConnect for the Mega Project 30% wind/5% solar case. Additionally, the savings reductions due to not expanding transmission reached \$1.5 billion, also for the Mega Project 30% wind/5% solar case.

The reliability analysis consisted of the following:

- Examined the WestConnect region without transmission constraints to determine the capacity value of wind and solar resources compared to other generation resources and load profiles.
- Examined the In-Area scenario for 2006 load and renewable profiles.
- Considered loss of load expectation (LOLE) in days/year and hours/year, as well as unserved energy in MWh/year.
- Examined wind, CSP and PV independently and jointly for varying levels of wind and solar penetration.

GE compared wind, CSP, and PV to perfect capacity. The amount of capacity needed for each penetration was:

- 10% wind, 1% solar – 11,490 MW wind, 600 MW of both CSP and PV
- 20% wind, 3% solar – 19,950 MW wind, 1,700 MW of both CSP and PV
- 30% wind, 5% solar – 29,940 MW wind, 2,900 MW of both CSP and PV

Mr. Jordan presented several plots of system risk with LOLE and unserved energy plotted against perfect capacity, wind only, CSP only, PV only, and Wind + CSP + PV. He noted that the results were all pretty much the same. Wind average capacity value is always in the 11-13% range, CSP in the 90-93% range, and PV in the 24-27% range. It should be noted that the PV power rating was done on the DC, not AC rating, so some 23% of inverter and power electronics losses were suffered. Rating the PV by its AC rating would have resulted in a higher capacity value. At the extremes, PV never got above 80% capacity but both CSP and wind reached 100% at times. A stakeholder asked if the results were different when looked at sub-hourly. Mr. Jordan said LOLE was historically done on an hourly basis, and if they wanted assess LOLE on a five-minute basis, GE would need five-minute load data.

Nick Miller, Intra-hour Variability and Operations

Mr. Miller presented an introduction to intra-hour variability. Up to this point of the meeting, GE's analysis has been on an hourly basis. This section presents some results from taking hourly load data and extrapolating to 10-minute variability. Mr. Miller noted that 10 minutes is a good divider between running reserves and cold/standby reserves, and GE also had 10-minute wind data to work with. Solar has not been analyzed yet and so is not included in this presentation.

Mr. Miller described the different sources and impacts of variability and uncertainty.

- Day-ahead forecast error is the major contributor to uncertainty.
- Sub-hourly changes in net load are the main source of variability.
- Sub-hourly variability drives dynamic reserve requirements.
- Handling of day-ahead uncertainty dominates dynamic reserve capability.

The summary statistics for 10-minute net load changes show that the overall 10-minute variability increase is relatively small, but the severity of the most extreme changes increases significantly. A series of plots with showing sigma as a function of wind and net load led to the following observations:

- Wind variability is not simply proportional to wind power level. Variability is lower when there is a lot of wind and only a little wind. The most variability is found in the mid-level ranges of wind production. Therefore, variability cannot be mitigated with conditions on wind power as this is not the right relationship.
- Periods of low net load tend to have considerably more variability.
- Wind variability differs with spatial diversity – wind in the Mega Project scenario is more concentrated and tends to look more like a single facility.
- The wider the distribution of wind, the less variability and less dependence on wind production level.

Typical grid operation practice in WECC is to have 3% of load as spinning reserves. GE explored the relationship of the 3% rule to the 10-minute deltas and found that the rule held for higher wind penetration levels. Load variability is roughly proportional to load level and the 3% of load rule roughly corresponds to the 10-minute variability results.

Mr. Miller presented a series of contour map plots that showed hourly load and wind level combinations at a 30% wind penetration level. These plots highlight the following:

- Load-only variability is highest at moderate load levels and is dominated by the diurnal load cycle.
- Wind variability appears to be affected by load level, something that is not intuitive, but could be a reflection of the diurnal patterns of wind, i.e. wind is more variable during the day at the same time load is highest.
- Net load variability increases with wind with an implied reserve requirement of 3%. This requirement is a function of both load level and wind level.
- Up reserves tend to be reduced at high load levels.
- Up reserves tend to increase with wind power.
 - Up reserve violations at 30% wind/5% solar penetration were 132.
 - Down reserve violations were only 8.

An examination of load and wind level contour plots for Arizona for the 30% wind/5% solar Local Priority scenario showed that state load is relatively unaffected by wind level and wind variability is highly dependent on load level, i.e. the diurnal effects are apparent. Arizona's net variability is also a mix of wind and load impacts and the worst reserve violations are during times of high load and moderate wind. Additionally, violations occur most often during times of low wind and moderate load. There were a total of 757 up-reserve violations counted and Mr. Miller speculated this might be due to wind forecast errors being more pronounced at lower wind levels. Plots of Wyoming for the same scenario show that wind variability is only slightly dependent on load and the high variability at the middle of wind power range is an expected characteristic. In Wyoming, the load variability is basically insignificant compared to wind variability and net load variability is totally dominated by wind variability. Wyoming wind generation also appears to be quite bi-modal, i.e., there is either lots of it or relatively little of it and Wyoming, with about twice as much wind as load, does not even come close to meeting reserve requirements with in-state resources. The up-reserve violation count in Wyoming was 2,075.

Mr. Miller summarized the presentation by noting that:

- Intra-hour variability increases with wind penetration levels.
- The smaller the area, the bigger impact of variability.
- On the WestConnect or WECC-wide level, variability looks similar; the change is incremental not revolutionary.
- At the area (state) level, variability starts to look very different, eventually dominated completely by wind (Wyoming).
- On a smaller scale (zonal), variability is clearly intractable and the old rules are unsuitable.
- Examination of sub-hourly performance suggests that rationally committed and dispatched systems, using imperfect day-ahead wind forecasts can work well, if reserve resources are shared.
- Modified rules for spin appear possible.

The next steps for the intra-hour variability analysis are:

- Develop additional understanding of the implications of the day-ahead wind forecast error on reserve capabilities.
- Examine other states, scenarios and renewable levels.
- Expand concepts to solar.
- Test implications of reserve sharing on inter-area performance issues.
- Explore how to address inter-area performance issues.
- Examine allocation of reserve resources, by generation type and dynamic capability.
- Conduct quasi-state simulation analysis.
- Further develop concepts for modified, simple rules for spinning reserves.

Charlie Smith, Discussion of Results

One attendee asked what Mr. Miller's presentation was showing us. Mr. Smith referred to NREL's collection of wind power output from the Buffalo Ridge wind project in Minnesota. He said a rule of thumb is to look at the changes in wind output at 1 second, 1 minute and from hour to hour. Generally, the standard deviation of changes in output at 1 second is 0.1%, meaning that a 100 MW wind project will increase 1-second variability by 100 kW. At one minute, the standard deviation is about 1%, so expect variability to increase by 1 MW for that 100 MW wind project. At one hour, variability increases to 10%. Mr. Miller said the 3x rule captures much of variation and applies to common sense power system operation practices.

There was a long discussion on the results for pumped storage hydro. Stakeholders questioned the result that no additional pumped storage hydro would be needed, even at 30% penetration scenarios, especially since pumped storage hydro pumps at night when load is low and wind production is often higher. One of the explanations is that pumped storage hydro may be more important for smaller areas, but taken footprint wide and WECC-wide, there is a lot of conventional hydro and additional pumped storage hydro may not be needed. Also, pumped storage hydro takes advantage of the price differential between peak and off-peak periods. Adding more wind to the system tends to drive down spot prices over all times, and therefore, potential revenues for pumped storage hydro are reduced. GE noted that the pumped storage hydro is utilized more in their study, but there was no need to build thousands of MW of additional pumped storage hydro. GE also emphasized that this study is not looking at economics and what the economically minimum amount of pumped storage hydro might be. The study is simply asking what is technically feasible and necessary to make 30% wind and solar work on the grid. There are economic and market design issues with regard to pumped storage hydro that are not within the scope of this study.

Another attendee remarked that consistent messages appear to be to emphasize larger balancing areas and that generating plants should be cycled. They asked if the GE study will strongly emphasize those findings, and if so, what the implications are. Mr. Piwko said GE will be as clear, concise and direct as they can, but they will not water the report down if the study results show something is needed.

One person asked Ms. Lew if NREL or GE has done any sensitivity analysis on the correlation of wind output across states or between regions. Ms. Lew said they have validated the wind ramp data but have not performed geographic diversity analysis on the hour-to-hour variations.

Another attendee noted the change in results and variability between 20% wind/3% solar and 30% wind/5% solar. They wondered if the change is linear or is there a certain penetration level where radical change in system operation practices is needed? GE noted that spatial diversity in the location of wind and solar plants helps with variability. At some point, variability crosses a threshold and changes are necessary. Mr. Piwko pointed out that in the scenarios that when wind and solar penetration is increased from 20% wind/3% solar to 30% wind/5% solar, there is an increase in wind and solar in the rest of WECC from 10% wind/1% solar to 20% wind/3% solar. An important next step is to separate the changes in the increase in in-footprint wind and solar

from the changes in wind and solar in the rest of WECC and determine what are the sources of changes in variability.

Paul Denholm of NREL asked about tying CSP with thermal storage; doesn't that serve a system-wide purpose. GE said they basically assumed storage was part of the CSP project and is converted to electrical generation with 99% efficiency. Since there are not a lot of operating CSP plants with storage, GE said they are a little soft on plant specifics and need some guidance from CSP experts. Mr. Piwko said GE has discussed profiling CSP thermal storage separate from the CSP system itself, and this could be useful follow-on work. When the WWSIS was designed, it was decided to emulate just one CSP profile, and assume that CSP storage is used at the end of the day and the start of the next day to manage variability or to provide reserves. Considering different methods for operating storage at CSP plants is an open question, and GE said they also could use guidance from CSP experts on this issue.

Steve Beuning of Xcel asked if GE's analysis is under-estimating minimum load issues, and they cited recent experience with increased numbers of minimum load in the Midwest ISO. He also wondered of the impact on generator retirements or operations if spot prices are reduced enough and generators are displaced more frequently. Mr. Smith said that is an important question and a capacity market may be needed for generators who cannot recover fixed costs in energy markets. Mr. Jordan said GE's mission is to determine if it is technically feasible to operate at 30% wind/5% solar, not if it is economical. He said it is a valid question; someone has to make money, but the question GE is trying to answer is if the grid can operate if policymakers require increasing levels of renewables through renewable portfolio standards, etc.

Debbie Lew on Next Steps

Ms. Lew said the original plan was to add two new scenarios, such as examining the impacts of higher levels of solar; higher levels of geographic diversity; or tying higher load correlation with renewable generation. So far, NREL and GE are not seeing any significant differences between the In-Area, Mega Project and Local Priority scenarios. Lack of sub-hourly solar data makes it difficult to consider a higher solar penetration level. An attendee asked what is a minimum size for PV plants to model. Mr. Piwko said there is some data for small PV sites, but the question is how to scale it up appropriately. GE needs data for hundreds of PV sites to model geographic diversity, or a big PV plant with a larger footprint to see the differences in variability in big PV plants versus small PV plants.

Ms. Lew said analysis on redispatching CSP storage needs to be done, as well as needing to understand the jump in variability when going from 20% wind/3% solar to 30% wind/5% solar in-footprint and 10% wind/1% solar to 20% wind/3% solar out-of-footprint. Are the changes in variability because of the increase in wind and solar penetration within the footprint, or from the increase in wind and solar penetration outside of the footprint? Other options to study include more consideration of storage at different time scales; the incorporation of plug-in hybrid electric vehicles; greater incorporation of demand response; replacing inflexible conventional units with more flexible conventional units; and carbon pricing sensitivity analyses. Ms. Lew then asked if

there are suggestions for further analysis, or more questions on the analysis that has been done to date.

A person asked if GE is considering ride-through capability for rooftop PV or doing any system stability analysis. GE said no; they are focusing only on statistical variability and analysis, as well as overall system operations with production simulations and quasi-steady-state analysis. Mr. Smith noted the activities of NERC's Integration of Variable Generation Task Force, and said the different requirements of FERC Order 661-A and IEEE-1547 need to be reconciled.

Jeff Mechenbier of PNM asked if GE's model reflects the additional costs of committing units day-ahead without gas storage, as energy costs will be affected if additional gas has to be procured in shorter time periods than day-ahead. Mr. Smith said this probably should be added to a list of questions to consider as the study moves forward.

Mr. Smith asked how the day-ahead wind forecast affects unit commitment, and how often is MAPS re-dispatched? Mr. Jordan said the wind forecast is taken as an input, and the balance of generation is committed to meet load. Dispatch is done hourly, with any intra-hour dispatch done on a 10-minute basis. A follow-up question concerned whether if the study results would improve wind forecasts were done on a six-hour-ahead basis. Mr. Jordan said they would need better data. Mr. Miller said some of this will be captured when GE picks interesting sub-hourly periods to analyze, such as high wind penetrations at 1-minute levels to assess whether there is sufficient ramping capability.

Mr. Jordan noted their study assumed natural gas prices of \$9.50/MMBTU, but gas prices are closer to \$3.50/MMBTU currently. What gas price should GE use? After some discussion, GE decided they may simply do a sensitivity study with different natural gas prices.

Mr. Smith asked about short-term storage and noted that Beacon Flywheels is operating some short-term storage in certain RTO markets. Should that be included in some way? Paul Denholm of NREL said the storage community wants their technology modeled and evaluated in a fair way, and if wind needs gas combustion turbines, why can't storage be added? Mr. Denholm also thought that capacity expansion models do not adequately represent storage. Mr. Jordan noted that previous wind integration studies, in calculating wind integration costs, compare the variability of wind with a flat block of generation, and the wind integration costs were generally about \$4-5/MWh. Building a pumped storage hydro plant would cost an order of magnitude more than that, absent another economic driver. Another attendee asked if adding wind adds value for additional storage, and if storage makes sense, what is the incremental value by adding storage? Mr. Jordan said they found that as wind was added, utilization of pumped storage hydro increased, but not to the point of adding more pumped storage hydro. Mr. Piwko thought there may be other uses storage brings to the grid that GE needs to consider, and some brainstorming may be necessary. A separate attendee said to be careful with short-term storage technologies, as they are energy limited and cannot participate in 10-minute markets. Mr. Piwko said they do not have the data to look at short-term storage but can look at storage that can operate from 10-to-30 minutes, as well as storage that can operate for longer periods than that.

GE asked the audience if GE is accurately modeling the market and the capability of existing generators. A meeting attendee said no: the ramps are understated, the ability of generators to turn down is overstated, and that impact on generator's O&M costs from changing operations due to high wind operations is not captured. Mr. Piwko noted that the California ISO in GE's work for the California Energy Commission also thought that combined cycle natural gas plants cannot turn down as much as GE assumed. However, GE's analysis of data from the EPA Continuous Emissions Monitoring System found that turnbacks in the operation of combined cycle natural gas plants even higher than GE assumed. Mr. Piwko said the assumptions in MAPS are based on real data and plant operations, and GE is open to making changes in MAPS if it can be verified.

A person noted that a large amount of the Bonneville Power Administration's increased wind integration rate is due to holding reserves for hourly scheduling, and is it safe to say that integrating wind at high levels is not feasible without sub-hourly scheduling? GE said that is basically right.

A meeting attendee remarked that carbon pricing cannot be disconnected from plant retirements, and the price of carbon will affect decisions on whether to keep plants in operation or not. Mr. Jordan said that is particularly true if more wind and solar sharply reduces the capacity factor and operating time of conventional units.

Ms. Lew closed the meeting by said there appears to be interest in looking further at storage; the impact of the changes in-footprint of going from 20% wind/3% solar to 30% wind/5% solar combined with the increase out-of-footprint from 10% wind/1% solar to 20% wind/3% solar. She said there is also interest in a high solar case, although the lack of sub-hourly solar production data is a problem.

APPENDIX A

**ATTENDEES AND CONFERENCE CALL PARTICIPANTS
FOR THE WESTERN WIND AND SOLAR INTEGRATION
STUDY STAKEHOLDER MEETING**

**DENVER, CO
JULY 30, 2009**

Meeting Attendees

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Carr, Tom, Western Interstate Energy Board
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Crumbley, Norma K., SWCA Environmental Consultants
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Darin, Tom, Western Resource Advocates
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Flood, Ron, Arizona Public Service
Freeman, Lavelle, GE
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Harper, Gary, Salt River Project
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